THIRD QUARTER REPORT FISCAL 2011

BRITISH COLUMBIA
The Best Place on Earth

BC hydro
FOR GENERATIONS

BC HYDRO & POWER AUTHORITY MANAGEMENT DISCUSSION AND ANALYSIS

The Management Discussion and Analysis reports on British Columbia Hydro and Power Authority's (BC Hydro or the Company) consolidated results and financial position for the three and nine month periods ended December 31, 2010 (fiscal 2011). This section should be read in conjunction with the Management Discussion and Analysis presented in the 2010 Annual Report, the 2010 Annual Consolidated Financial Statements of BC Hydro, and the interim consolidated financial statements of BC Hydro for the three and nine month periods ended December 31, 2010 and 2009. This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of BC Hydro. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward-looking statements.

BC Hydro's results for the third quarter of fiscal 2011 benefited from higher domestic gross margins primarily due to higher average customer rates, higher energy trading margins and lower finance charges, partially offset by higher non-energy operating costs than in the same quarter in the prior year.

HIGHLIGHTS

- Net income after regulatory account transfers for the three and nine month periods ended December 31, 2010 was $171 million and $381 million, respectively, compared to $113 million and $302 million for the same periods in fiscal 2010.

- In December 2010, the British Columbia Utilities Commission (BCUC) approved the Negotiated Settlement Agreement (NSA) on BC Hydro's F2011 Revenue Requirements Application (RRA). The final rate increase for fiscal 2011 is 6.11 per cent for all customer classes, with a 4.71 per cent credit applied to charges payable under all other approved rates, except for the Deferral Account Rate Rider (DARR), for the period January 1, 2011 to March 31, 2011 to reflect the NSA adjustments. The NSA also confirmed the DARR of 4.0 per cent for the period from April 1, 2010 through December 31, 2010, after which the DARR will be 2.5 per cent. In combination, the overall annual bill impact of these adjustments for fiscal 2011 is a rate increase of 7.29 per cent. These final rates and other provisions in the NSA are reflected in BC Hydro's results for the quarter and fiscal year to date.

- Hydro generation levels in the quarter were in line with the same period in the prior year. Average water inflows into system reservoirs during the quarter were 4 per cent above average (average from 1971-2000). Due to the higher inflows in the third quarter, the current forecast for fiscal 2011 inflows is 85 per cent of average.

- BC Hydro's capital plan for fiscal 2011 is $1.7 billion as the Company continues its programs to address load growth and renew and revitalize its aging infrastructure. Property, plant and equipment expenditures for the quarter of $375 million were comparable to the same period in the prior year, with higher expenditures on transmission projects offset by lower generation and general capital expenditures.

	For the three months ended December 31			*For the nine months ended December 31*		
(in millions)	**2010**	2009	Change	**2010**	2009	Change
Net Income	**$ 171**	$ 113	$ 58	**$ 381**	$ 302	$ 79
Accrued Payment to the Province	**$ 146**	$ 60	$ 86	**$ 216**	$ 101	$ 115
Number of Domestic Customers	**N/A**	N/A	N/A	**1,848,206**	1,822,629	25,577
GWh Sold (Domestic)	**13,702**	13,613	89	**36,386**	36,328	58
Total Reservoir Storage (GWh)	**N/A**	N/A	N/A	**20,665**	21,182	(517)

(in millions)	As at December 31, 2010	(Revised) As at March 31, 2010	Change
Total Assets	**$ 19,184**	$ 18,098	$ 1,086
Retained Earnings	**$ 2,786**	$ 2,621	$ 165
Debt to Equity	**80 : 20**	80 : 20	N/A

CONSOLIDATED RESULTS OF OPERATIONS

As a rate-regulated utility, BC Hydro applies various accounting policies that are acceptable under Canadian generally accepted accounting principles (GAAP) for rate regulated enterprises but differ from enterprises that do not operate in a rate-regulated environment. These policies allow for the deferral of amounts that under GAAP would otherwise be recorded as expenses or income in the current accounting period. The deferred amounts are either recovered or refunded through future rate adjustments.

Commencing in fiscal 2011, BC Hydro changed its reporting of regulatory account transfers on the statement of operations to report individual line items net of transfers to regulatory accounts, as compared to prior years in which net transfers to regulatory accounts were reported as a single separate line item and income was reported both before and after regulatory account transfers. Amounts in the prior year's comparative statement of operations have been reclassified to conform to the current year's presentation of changes in regulatory accounts and the current year's classification of operating expenses. Detail on regulatory account transfers can be found in the MD&A and in Note 4 to the Interim Consolidated Financial Statements.

The transfers to regulatory accounts reflected in net income on the consolidated statement of operations include: variances between forecast and actual amounts for certain costs, including cost of energy, trade income and finance charges; certain amounts incurred in the current period that are deferred for future recovery in rates (such as demand-side management expenditures and liability provisions); interest accrued on regulatory accounts where allowed; and amortization of regulatory accounts into income.

Net transfers to regulatory accounts of $92 million for the quarter were mainly to the Non-Heritage Deferral Account (NHDA) due to higher than planned cost of energy, partially offset by lower than planned purchases for future trade; from the Heritage Deferral Account (HDA) due to lower than planned energy costs in the quarter; additions to the Trade Income Deferral Account (TIDA) for the variance between planned and actual trade income; and expenditures on demand-side management programs (DSM).

Net income for the quarter ended December 31, 2010 was $171 million, an increase of $58 million from the same period in the prior year mainly as a result of higher domestic revenues due to higher average customer rates and an increase in the rate rider, lower operating costs primarily due to lower expenditures for electricity and gas purchases, lower finance charges, and higher trade income. All variances are after the effect of applicable transfers to regulatory accounts.

For the nine months ended December 31, 2010 net transfers to regulatory accounts of $408 million were mainly to the NHDA due to higher than planned energy costs resulting from low water inflows and lower than planned domestic revenues, partially offset by lower purchases from IPPs and purchases for future trade; additions to the TIDA for the variance between planned and actual trade income; and expenditures on DSM.

Net income for the nine months ended December 31, 2010 was $381 million, an increase of $79 million from the same period in the prior year mainly as a result of higher domestic revenues due to higher average customer rates and an increase in the rate rider, lower operating costs primarily due to lower expenditures for electricity and gas purchases, lower finance charges and higher trade income. All variances are after the effect of applicable transfers to regulatory accounts.

REVENUES

For the three months ended December 31	*(in millions)*		*(gigawatt hours)*	
		(Revised)		*(Revised)*
	2010	2009	**2010**	2009
Domestic				
Residential	**$ 414**	$ 372	**5,093**	5,039
Light industrial and commercial	**322**	290	**4,641**	4,602
Large industrial	**140**	121	**3,457**	3,346
Other energy sales	**55**	66	**511**	626
Total Domestic Revenue Before Regulatory Transfer	**931**	849	**13,702**	13,613
Domestic load variance regulatory transfer	**5**	35	**-**	-
Total Domestic	**$ 936**	$ 884	**13,702**	13,613
Trade				
Electricity - Gross	**$ 252**	$ 352	**6,275**	10,274
Less: forward electricity purchases[1]	**(136)**	(205)	**-**	-
Electricity - Net	**116**	147	**-**	-
Gas - Gross	**252**	212	**6,504**	4,764
Less: forward gas purchases[1]	**(245)**	(167)	**-**	-
Gas - Net	**7**	45	**-**	-
Total Trade Revenue Before Regulatory Transfer	**123**	192	**12,779**	15,038
Trade regulatory transfer (to TIDA)	**205**	441	**-**	-
Total Trade	**$ 328**	$ 633	**12,779**	15,038
Total	**$ 1,264**	$ 1,517	**26,481**	28,651

For the nine months ended December 31	*(in millions)*		*(gigawatt hours)*	
		(Revised)		*(Revised)*
	2010	2009	**2010**	2009
Domestic				
Residential	**$ 969**	$ 896	**12,183**	12,217
Light industrial and commercial	**925**	841	**13,272**	13,198
Large industrial	**399**	348	**9,870**	9,691
Other energy sales	**173**	164	**1,061**	1,222
Total Domestic Revenue Before Regulatory Transfer	**2,466**	2,249	**36,386**	36,328
Domestic load variance regulatory transfer	**22**	109	**-**	-
Total Domestic	**$ 2,488**	$ 2,358	**36,386**	36,328
Trade				
Electricity - Gross	**$ 799**	$ 1,039	**19,995**	26,039
Less: forward electricity purchases[1]	**(475)**	(616)	**-**	-
Electricity - Net	**324**	423	**-**	-
Gas - Gross	**632**	434	**15,806**	12,955
Less: forward gas purchases[1]	**(540)**	(352)	**-**	-
Gas - Net	**92**	82	**-**	-
Total Trade Revenue Before Regulatory Transfer	**416**	505	**35,801**	38,994
Trade regulatory transfer (to TIDA)	**636**	1,617	**-**	-
Total Trade	**$ 1,052**	$ 2,122	**35,801**	38,994
Total	**$ 3,540**	$ 4,480	**72,187**	75,322

[1] Forward purchases include derivatives which are deducted from gross sales in accordance with GAAP.

Total revenue for the three and nine months ended December 31, 2010 was $1,264 million and $3,540 million respectively, decreases of $253 million and $940 million compared with the same periods in the prior year. Domestic revenues were higher due to higher average rates in all customer classes while trade revenues were lower due to lower electricity trade volumes and prices, partially offset by higher gas trade volumes in the quarter and higher gas trade volumes and prices for the nine month period.

Domestic Revenues

Total domestic revenues of $936 million for the third quarter of fiscal 2011 were $52 million or 6 per cent higher than in the same period in the previous year. Total domestic revenues of $2,488 million for the nine months ended December 31, 2010 were $130 million or 6 per cent higher than in the same period in the previous year. Domestic sales volumes for the quarter and nine months were comparable to the prior year periods. The increase for the quarter and year to date was due to higher average customer rates in all rate classes which were increased on April 1, 2010 by 6.11 per cent as per BC Hydro's RRA for fiscal 2011. The increase was approved as final in the NSA on December 2, 2010, with a credit of 4.71 per cent to be applied for the period January 1, 2011 to March 31, 2011. The rate rider increased from 1 per cent to 4 per cent for the period April 1, 2010 to December 31, 2010 and will be decreased to 2.5 per cent commencing January 1, 2011. Any variances between actual and planned load are deferred to the NHDA.

Trade Revenues

BC Hydro's electricity system is interconnected with systems in Alberta and the Western United States. Interconnection facilitates sales and purchases of electricity outside of British Columbia. Energy trade activities are carried out by Powerex, a wholly owned subsidiary of BC Hydro. Trade activities help BC Hydro balance its system by being able to import energy to meet domestic demand when there is a supply shortage in the system due to such factors as low water inflows. Exports are made only after ensuring domestic demand requirements can be met.

Gross trade revenue for the quarter ended December 31, 2010 decreased by $60 million from the same period in the prior year, primarily due to a decrease of $100 million in gross electricity revenue, partially offset by an increase of $40 million in gross gas revenue. The decrease in gross electricity revenue was primarily due to a 39 per cent decrease in sales volumes primarily due to lower demand. The increase in gross gas revenue was driven by a 37 per cent increase in gas sales volumes, reflecting Powerex's objective of growing its gas business. Deducted from the gross trade revenue figures above are forward purchases, which saw a net increase of $9 million over the prior year. Forward purchases are deducted from gross trade revenue, which includes forward sales, in order to report the results of forward transactions on a net basis in accordance with GAAP.

Gross trade revenue for the nine months ended December 31, 2010 decreased by $42 million from the same period in the prior year due to a decrease in electricity revenue of $240 million, partially offset by an increase in gas revenue of $198 million. The decrease in gross electricity revenue was primarily driven by a 23 per cent decrease in sales volumes over the prior year. The increase in gross gas revenue was due to a 22 per cent increase in gas sales volumes and a 15 per cent increase in the average gas sale price. The decrease in electricity volumes and prices was primarily a result of low demand in California due to the economic downturn and a cool summer along the U.S. west coast. Deducted from gross trade revenue are forward purchases, which increased by a net $47 million compared to the prior year. Forward transactions are reported on a net basis in accordance with GAAP.

OPERATING COSTS

In fiscal 2011, BC Hydro changed its classification of operating expenses to a presentation of costs based on the nature of the expenditures. Amounts previously reported as operations, maintenance and administration are now classified by the nature of the expense as outlined in Note 8 in the Interim Consolidated Financial Statements.

For the three and nine months ended December 31, 2010, total operating costs of $986 million and $2,835 million were $290 million and $958 million lower, respectively, than in the same periods in the prior year. The decreases are primarily due to a reduction in the cost of energy as a result of lower trade energy purchases and lower materials and services expenditures, partially offset by increases in personnel expenditures, higher amortization expense, higher grants and taxes and other operating costs during both the three and nine months ended December 31, 2010.

COST OF ENERGY

Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand, and environmental and social impacts.

Energy costs are comprised of the following sources of supply:

For the three months ended December 31	*(in millions)*		*(gigawatt hours)*		*($ per MWh)*	
		(Revised)		*(Revised)*		*(Revised)*
	2010	2009	**2010**	2009	**2010**	2009
Domestic						
Water rental payments	**$ 88**	$ 86	**11,769**	11,804	**$ 7.48**	$ 7.06
Purchases from Independent Power Producers	**178**	167	**2,763**	2,605	**64.57**	64.18
Other electricity purchases - Domestic	**30**	30	**829**	644	**36.35**	46.58
Gas for thermal generation	**13**	13	**94**	89	**133.96**	146.07
Transmission charges and other expenses	**(2)**	13	**76**	32	**-**	-
Allocation to/from trade energy	**(7)**	3	**(166)**	(42)	**37.31**	38.95
Total Domestic Cost of Energy Before RegulatoryTransfers	**300**	312	**15,365**	15,132	**19.51**	20.62
Domestic cost of energy regulatory transfers	**(16)**	(2)	**-**	-	**-**	-
Total Domestic	**$ 284**	$ 310	**15,365**	15,132	**$ 19.51**	$ 20.62
Trade						
Electricity - Gross	**$ 196**	$ 313	**6,118**	10,199	**$ 32.04**	$ 30.69
Less: forward electricity purchases[1]	**(136)**	(205)	**-**	-	**-**	-
Electricity - Net	**60**	108	**-**	-	**-**	-
Remarketed gas - Gross	**240**	186	**6,820**	4,953	**35.19**	37.55
Less: forward gas purchases[1]	**(245)**	(167)	**-**	-	**-**	-
Other gas purchases - Trade - Net	**(5)**	19	**-**	-	**-**	-
Transmission charges and other expenses	**46**	51	**-**	-	**-**	-
Allocation to/from domestic energy	**7**	(3)	**166**	42	**37.31**	38.95
Total Trade Cost of Energy Before RegulatoryTransfers	**108**	175	**13,104**	15,194	**38.51**	24.96
Trade cost of energy regulatory transfers	**175**	419	**-**	-	**-**	-
Total Trade	**$ 283**	$ 594	**13,104**	15,194	**$ 38.65**	$ 52.53
Total Energy Costs	**$ 567**	$ 904	**28,469**	30,326	**$ 27.76**	$ 36.54

[1] Other electricity purchases in dollars include purchases for trade activities shown net of derivatives. Gigawatt hours (GWh) and $ per Megawattt hour (MWh) are shown at gross cost.
[2] Total cost per MWh includes other electricity purchases at gross cost.

For the nine months ended December 31	*(in millions)*		*(gigawatt hours)*		*($ per MWh)*	
		(Revised)		*(Revised)*		*(Revised)*
	2010	2009	**2010**	2009	**2010**	2009
Domestic						
Water rental payments	**$ 208**	$ 207	**27,047**	29,634	**$ 7.69**	$ 6.82
Purchases from Independent Power Producers	**532**	395	**8,727**	6,422	**61.01**	61.49
Other electricity purchases - Domestic	**114**	76	**3,145**	2,036	**36.29**	37.33
Gas for thermal generation	**34**	38	**194**	345	**173.16**	110.30
Transmission charges and other expenses	**22**	50	**633**	80	**-**	-
Allocation to/from trade energy	**25**	54	**586**	1,403	**39.41**	33.94
Total Domestic Cost of Energy Before RegulatoryTransfers	**935**	820	**40,332**	39,920	**23.18**	20.54
Domestic cost of energy regulatory transfers	**(152)**	(45)	**-**	-	**-**	-
Total Domestic	**$ 783**	$ 775	**40,332**	39,920	**$ 19.41**	$ 19.42
Trade						
Electricity - Gross	**$ 636**	$ 893	**20,294**	27,190	**$ 31.34**	$ 32.84
Less: forward electricity purchases[1]	**(475)**	(616)	**-**	-	**-**	-
Electricity - Net	**161**	277	**-**	-	**-**	-
Remarketed gas - Gross	**588**	426	**16,099**	13,490	**36.52**	31.58
Less: forward gas purchases[1]	**(540)**	(352)	**-**	-	**-**	-
Other gas purchases - Trade - Net	**48**	74	**-**	-	**-**	-
Transmission charges and other expenses	**140**	174	**-**	-	**-**	-
Allocation to/from domestic energy	**(25)**	(54)	**(586)**	(1,403)	**39.41**	33.94
Total Trade Cost of Energy Before RegulatoryTransfers	**324**	471	**35,807**	39,277	**34.75**	27.67
Trade cost of energy regulatory transfers	**542**	1,482	**-**	-	**-**	-
Total Trade	**$ 866**	$ 1,953	**35,807**	39,277	**$ 45.05**	$ 65.39
Total Energy Costs	**$ 1,649**	$ 2,728	**76,139**	79,197	**$ 31.47**	$ 42.22

[1] Other electricity purchases in dollars include purchases for trade activities shown net of derivatives. Gigawatt hours (GWh) and $ per Megawattt hour (MWh) are shown at gross cost.
[2] Total cost per MWh includes other electricity purchases at gross cost.

Total energy costs, after regulatory account transfers, for the third quarter of fiscal 2011 were $567 million, 37 per cent lower than the same period last year. For the nine months ended December 31, 2010 total energy costs after regulatory account transfers were $1,649 million, or 40 per cent lower than the same period last year. The decrease in the quarter was primarily due to lower purchases of electricity for trade and lower domestic transmission costs, partially offset by increased purchases of natural gas for trade and higher domestic energy purchases from Independent Power Producers (IPPs). The year to date decrease was primarily due to lower purchases of trade electricity, partially offset by higher purchases of natural gas for trade.

Domestic Energy Costs

Domestic energy costs before regulatory transfers of $300 million for the third quarter were comparable with the same period in the prior year. For the nine months ended December 31, 2010 domestic energy costs before regulatory transfers of $935 million were 14 per cent higher than in the same period in the prior year. During the third quarter, higher purchases from IPPs were offset by lower transmission costs and purchases for future trade. The increase year to date was mainly due to higher purchases from IPPs and higher market energy purchases, partially offset by lower transmission costs and purchases for future trade. The increase in IPP purchases was primarily due to two new bio-energy projects which started in late fiscal 2010, agreements in the current year to purchase additional energy from two existing IPPs, and increased purchases from Alcan that BC Hydro was required to make due to Alcan's reduced smelter load. Year to date market electricity purchases were higher as the reduced generation levels resulting from lower water inflows required BC Hydro to purchase energy from the market to meet domestic load requirements. Water rental costs for the nine months were comparable to the prior year as an 8.74 per cent increase

on water rental fees and additional water rental fees associated with the one-third interest in the Waneta dam and generating facility acquired in March 2010 was offset by the impact of lower generation levels due to lower water inflows. Variances between actual and planned domestic cost of energy are transferred to the HDA and NHDA.

Trade Energy Costs

In the third quarter, gross trade energy costs decreased by $58 million compared with the same period in the prior year, primarily due to a decrease of $117 million in gross electricity purchases partly offset by a $54 million increase in gross gas purchases. The decrease in gross electricity purchases during the quarter reflects a 40 per cent decrease in purchase volumes consistant with the decrease in electricity sales volumes. The increase in gross gas purchases is primarily a result of a 38 per cent increase in gas purchase volumes, consistent with the increase in gas sales volumes. Included in the figures above is a net increase of $9 million in forward purchases, which are deducted from gross trade energy costs, and netted against forward sales within gross trade revenue in accordance with GAAP.

Gross trade energy costs for the nine months ended December 31, 2010 decreased by $100 million compared with the same period in the prior year primarily due to a $257 million decrease in gross electricity purchases for trade, partially offset by a $162 million increase in gross gas purchases. Gross electricity purchases reflect a 5 per cent decrease in the average electricity purchase price, and a 25 per cent decrease in electricity purchase volumes. As with electricity sales, this is primarily due to the economic downturn and a cool summer, which reduced demand in California. Remarketed gas purchase costs increased due to a 16 per cent increase in the average gas purchase price reflecting increased demand over the summer period in the eastern U.S., and a 19 per cent increase in gas purchase volumes reflecting Powerex's intention to grow its gas business. Deducted from gross trade energy costs are forward purchases, which increased by a net $47 million compared to the prior year. Forward purchases are netted against forward sales within gross revenue in accordance with GAAP.

Water Inflows

Water inflows into BC Hydro's reservoirs in the third quarter of fiscal 2011 were 4 per cent above average, increasing the most current fiscal 2011 forecast from 83 per cent to 85 per cent of average.

The BC Hydro reservoirs have been managed such that the combined storage in BC Hydro reservoirs at December 31, 2010 was 98 per cent of average, compared to 100 per cent of average at December 31, 2009. Storage on the Williston reservoir on the Peace River system is 85 per cent of average, and the Kinbasket reservoir on the Columbia River system is at 116 per cent of average.

Personnel Expenses

Personnel expenses include labour, benefits and employee future benefits. Personnel costs, after net regulatory transfers, of $131 million for the quarter and $402 million for the nine months ended December 31, 2010 were $17 million and $52 million higher, respectively, than in the same periods in the prior year primarily due to the integration of the British Columbia Transmission Corporation (BCTC) with BC Hydro in July 2010 and as a result of higher non-current pension costs.

Materials and External Services

Materials and external services include expenditures for operating and maintenance materials and services provided by third parties. Expenditures on materials and external services, after net regulatory transfers, of $144 million for the quarter and $430 million for the nine months ended December 31, 2010 were $18 million and $10 million lower, respectively, as compared to the same periods in the prior year. The reductions are mainly due to changes in levels of maintenance and other operational activities, including expenditures in fiscal 2010 on initiatives not required in the current year and lower expenditures on Mountain Pine Beetle vegetation maintenance, autosplice work programs and generation operations civil and maintenance initiatives in the current year.

Capitalized Costs

Capitalized costs are overhead costs incurred to support capital expenditures and are transferred from operating costs to property, plant and equipment. Capitalized costs for the three and nine month periods ended December 31, 2010 are $67 million and $192 million, respectively, compared to $65 million and $207 million, respectively, for the same periods in the prior year. The differences are primarily due to a change in the allocation of capitalized overhead costs among quarters during a fiscal year. Prior to fiscal 2011, BC Hydro allocated capitalization of overhead costs among quarters during a fiscal year on a straight-line basis. In fiscal 2011, overhead costs are allocated based on actual levels of capital expenditures during each period.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, asset retirement obligation (ARO) assets, amortization of customer contributions and the amortization of certain regulatory assets and liabilities. For the three and nine month periods ended December 31, 2010, amortization and depreciation expense was $145 million and $396 million, respectively, compared with $121 million and $361 million, respectively, in the same periods in the prior year. The increase was primarily due to higher assets in service as a result of BC Hydro's capital expenditure program and higher net regulatory account amortization.

Grants and Taxes

As a Crown Corporation, BC Hydro is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts. Total grants, school taxes and other local taxes of $46 million for the quarter and $136 million for the nine months ended December 31, 2010 were comparable to the same periods in the prior year.

Other Costs

Other operating costs primarily include gains or losses on the disposal of assets. Costs of $20 million for the quarter and $14 million for the nine months ended December 31, 2010 are $23 million and $22 million higher, respectively, than for the same periods in the prior year. The increases are primarily due to the write down of two regulatory asset accounts as directed by NSA.

FINANCE CHARGES

Finance charges, after net regulatory transfers, of $107 million for the third quarter of fiscal 2011 and $324 million for the nine months ended December 31, 2010 were $21 million and $61 million lower, respectively, than in the same periods in the prior year. Finance charges before regulatory account transfers were higher in the quarter than in the prior year due to a higher average volume of debt, lower interest during construction, higher interest rates, higher other finance charges and higher mark to market adjustments on certain risk management activities and foreign exchange translation gains and losses on U.S. dollar short term borrowings. For the nine months ended December 31, 2010 finance charges before regulatory account transfers were higher than the prior year due to a higher average volume of debt, lower foreign exchange revaluation gains on net unhedged U.S. dollar exposures due to a lesser strengthening of the Canadian dollar against the U.S. dollar in fiscal 2011 as compared to a more significant strengthening in the prior year, higher other finance charges, higher financing lease interest expense, higher interest rates and higher mark to market adjustments on certain risk management activities and foreign exchange translation gains and losses on U.S. dollar short term borrowings. Variances between actual and planned finance charges are transferred to the Foreign Exchange Gains and Losses Regulatory Account and the Finance Charges Regulatory Account, which results in a net decrease in finance charges notwithstanding higher actual costs.

REGULATORY TRANSFERS

BC Hydro has established various regulatory accounts with the approval of the British Columbia Utilities Commission (BCUC). Regulatory accounts allow BC Hydro to defer certain types of revenue and cost variances through transfers to and from the accounts which have the effect of adjusting net income. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC.

The net change in regulatory accounts on the consolidated statement of operations includes: 1) the deferral of differences between planned and actual results for cost of energy (including variances related to load), trade income, finance charges and non-current pension costs; 2) costs deferred for future recovery in rates, such as costs for DSM and Site C; and 3) interest accrued on regulatory accounts, where allowed, and amortization of regulatory accounts.

Regulatory transfers are comprised of the following:

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2010**	2009	**2010**	2009
Variances between forecast and actual costs				
Energy deferral accounts	**$ 51**	$ 45	**$ 274**	$ 251
Finance charges	**5**	(30)	**(11)**	(108)
Non-current pension deferral	**1**	21	**1**	64
Other	**2**	(18)	**(9)**	(61)
	59	18	**255**	146
Deferral of costs for future recovery in rates				
Demand Side Management	**23**	31	**73**	74
Return on Equity	**-**	14	**-**	42
Other	**22**	13	**70**	61
	45	58	**143**	177
Amortization of regulatory accounts	**(23)**	(18)	**(18)**	(51)
Interest on regulatory accounts	**11**	11	**28**	29
Net change in regulatory accounts	**$ 92**	$ 69	**$ 408**	$ 301

For the three and nine months ended December 31, 2010, BC Hydro transferred, on a net basis, $92 million and $408 million to regulatory accounts, compared with the transfer of $69 million and $301 million to the regulatory accounts during the same periods last year. The majority of the transfers relate to the cost of energy deferral accounts. The net asset balance in the regulatory asset and liability accounts as at December 31, 2010 was an asset of $2,146 million compared to $1,713 million at March 31, 2010.

The significant transfers to the energy deferral accounts reflect lower than planned domestic revenues due to lower consumption, higher energy purchase costs as higher market energy purchases were required due to low water inflows, and lower than planned trade income due to low price spreads caused by lower commodity prices for electricity and natural gas. The finance charges deferral reflects a year to date positive variance on short-term interest rates, partially offset by lower foreign exchange gains on unhedged U.S. dollar exposures during the third quarter. Non-current pension costs are on plan in the current period as compared to the first half of fiscal 2010 when they were significantly higher than planned due to the net actuarial loss experienced by the BC Hydro pension plan in fiscal 2009. DSM transfers in the third quarter are net of a $10 million write down of the DSM regulatory account balance as required by the NSA. The change in amortization of regulatory accounts reflects the changing composition of the balances subject to amortization.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board (AcSB) confirmed the adoption of IFRS in place of Canadian GAAP for publicly accountable enterprises. The new requirements are effective for interim and annual reporting periods beginning on or after January 1, 2011. In October 2009, the Canadian Public Sector Accounting Board (PSAB) confirmed the existing guidance whereby Government Business Enterprises (GBEs), which BC Hydro is classified as, adhere to standards for publicly accountable enterprises in the private sector. In 2010, the AcSB issued guidance allowing qualifying entities with rate-regulated activities be permitted, but not required, to continue applying the accounting standards in Part V of the CICA Handbook – Accounting for an additional year rather than adopting IFRS for annual periods beginning on or after January 1, 2011. BC Hydro will use the deferral option.

Areas with significant differences between IFRS and Canadian GAAP that would impact BC Hydro include: Regulatory Accounting, Property, Plant & Equipment, Provisions and Contingent Liabilities, Employee Benefits, and the overall presentation of financial statements. The initial adoption of IFRS under IFRS 1, *First-time Adoption of International Financial Reporting Standards*, would also result in a number of significant changes. The Company is currently evaluating the impact of the transition to IFRS on its consolidated financial statements.

PAYMENT TO THE PROVINCE

Under a Special Directive from the Province, BC Hydro is required to make an annual payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of BC Hydro's distributable surplus for the most recently completed fiscal year assuming that the debt to equity ratio, as defined by the Province, after deducting the Payment, is not greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment will be based on the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The dividend accrued year to date at December 31, 2010 is $216 million, which is below 85 per cent of the distributable surplus due to the 80:20 cap.

LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek refunds, damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At December 31, 2010, Powerex was owed US $265 million (CDN $264 million) by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

Due to the ongoing nature of the regulatory and legal proceedings against Powerex, management cannot predict the outcomes of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the California energy crisis. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that are ultimately collected or paid may differ from management's current estimates. Management has not disclosed the provision amounts or ranges of expected outcomes due to the potentially adverse effect on the process.

REGULATION

Revenue Requirement Application (RRA)

In the process of regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy and achieve a certain return on equity (ROE). The annual rate of ROE is equal to the pre-income tax annual rate of

return allowed by the BCUC to the most comparable investor-owned energy utility regulated under the *Utilities Commission Act* with a 1.63 per cent adder for the fiscal 2010, 2011 and 2012 years. This is in accordance with Heritage Special Direction No. HC2 as amended by Order in Council No. 074 dated February 17, 2009. The allowed rate of ROE for fiscal 2011 is 14.37 per cent, and is higher than the prior year's allowed rate of 13.05 per cent due to the higher rate of return allowed for Terasen Gas Inc., upon which BC Hydro's rate of return is based.

BC Hydro's fiscal 2011 RRA was filed with the BCUC on March 3, 2010 requesting a 6.11 per cent rate increase and that the rate rider increase by 3 per cent. The rate increases were approved by the BCUC on an interim basis effective April 1, 2010 and are applied to bill customers and recognize revenue in fiscal 2011.

BC Hydro and interveners agreed, with BCUC approval, to enter into a Negotiated Settlement Process, to resolve the application. A Negotiated Settlement Agreement (NSA) was reached and was approved by the BCUC on December 2, 2010.

The NSA confirmed the 6.11 per cent rate increase as final with a 4.71 per cent credit applied to the charges payable under all other approved rates, except for the DARR, for the period January 1 to March 31, 2011 to reflect the NSA adjustments. The DARR was finalized at 4 per cent for the April 1 through December 31, 2010 period and 2.5 per cent thereafter. In combination, the overall fiscal 2011 annual bill impact of these adjustments to customers is 7.29 per cent.

The main financial impacts of the NSA in fiscal 2011 include write offs of $5.5 million to the Procurement Enhancement Initiative (PEI) regulatory account balance and $10.3 million to the DSM regulatory account balance and a reduction of $35 million in the operating cost forecast for rate setting purposes only. These changes will have an impact on fiscal 2011 financial results.

The NSA also includes several commitments by BC Hydro to address some specific issues to potentially mitigate future rate impacts in its next revenue requirements application which is to cover a three-year test period and to be reviewed in an oral public hearing.

F2012 – 2014 RRA

BC Hydro's F2012–2014 RRA will be filed with the BCUC in Spring 2011, requesting a general rate increase of approximately 9.7 per cent per year in each of F2012–2014. BC Hydro will be requesting these increases because of: an increase in capital-related costs (amortization and financing costs) due to higher levels of investment in assets; an increase in the ROE as BC Hydro's asset base grows; and a reduction in forecast trade income due to weaker export market conditions. The BCUC must approve any requested rate increases. A decision from the BCUC on the F2012–2014 RRA is expected in Winter 2011.

Rate Mitigation

The provincial government has taken steps to ease the rate burden for BC Hydro customers. As of January 1, 2011, water rental increases that BC Hydro pays for water that flows through our generating stations will now be tied to inflation instead of being tied to BC Hydro's rate increases. In addition, the Province has authorized BC Hydro to move to an assets-in-service rate base as opposed to debt plus equity, which puts BC Hydro in line with most utilities in Canada and is seen as a fairer way to calculate the government's return on its investment. These actions will mitigate future rate increases for customers.

Hugh Keenleyside Spillway Gates Project

BC Hydro filed an application with the BCUC on July 16, 2010 for acceptance of an estimated $90 million of expenditures associated with the Hugh Keenleyside Spillway Gates project. The spillway gate system needs to be refurbished and upgraded to ensure that it can reliably pass water in a flood event or post-earthquake reservoir drawdown. The BCUC issued its decision on December 2, 2010 finding that the expected expenditures to complete the project are in the public interest.

Interior to Lower Mainland Transmission (ILM) Project

The BCUC is reconsidering the ILM application for the purpose of determining the adequacy of First Nations consultation on this project from 2006 up to the point when the Certificate of Public Convenience and Necessity (CPCN) was issued in August 2008. Construction on this project has been suspended, pending a decision on this matter.

The Supreme Court of Canada issued a decision on October 28, 2010 regarding the Carrier Sekani case, finding that the Crown's duty to consult with First Nations is limited to any adverse impacts flowing from a specific proposed project, not to any historical grievances arising from prior activities. First Nations groups impacted by the ILM project subsequently requested the BCUC to withdraw those portions of their evidence that had been submitted in the ILM reconsideration proceeding relating to past infringements.

First Nation groups applied to the British Columbia Supreme Court for judicial review of the decision in June 2009 granting an Environmental Assessment Certificate (EAC) for the project. A formal hearing on this matter, originally scheduled for November 29, 2010, will now take place in February 2011 and a decision will follow.

Remote Community Electrification (RCE) Program

BC Hydro filed CPCN applications for the communities of Tsay Keh, Fort Ware and Elhateese with the BCUC on December 23, 2010. These RCE projects will allow BC Hydro to remotely provide reliable electricity supply to these customers through diesel generation.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the third quarter was $172 million, compared with cash flow provided by operating activities of $126 million for the same period last year. For the nine months ended December 31, 2010, cash flow provided by operating activities was $325 million, compared with cash flow provided by operating activities of $92 million in the same period last year. The increase in the quarter was primarily due to an increase in net income. The increase year to date was primarily due to an increase in net income and changes in working capital relative to the prior year.

The long-term debt balance net of sinking funds at December 31, 2010 was $11.6 billion, compared with $10.7 billion at March 31, 2010. The increase was mainly a result of net long-term bond issues totaling $663 million ($670 million par value) less long-term bond retirements totaling $150 million ($150 million par value) and an increase in revolving borrowings of $435 million (the increases in short-term and long-term debt include BCTC additions which do not affect cash flow). These increases were partially offset by net foreign exchange revaluation gains of $23 million, amortization of premiums of $12 million and a decrease of $11 million in debt due to fair value hedge accounting. The increase in revolving borrowings was due to the funding of capital expenditures and the Payment to the Province.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

	For the three months ended December 31		*For the nine months ended December 31*	
(in millions)	**2010**	2009	**2010**	2009
Distribution improvements and expansion	**$ 104**	$ 100	**$ 319**	$ 322
Generation replacements and expansion	**113**	123	**305**	358
Transmission lines and substations replacements & expansion	**108**	79	**329**	275
General, including IT, buildings and vehicles	**50**	73	**157**	189
Capital lease	**-**	-	**171**	-
	$ 375	$ 375	**$ 1,281**	$ 1,144

Total property, plant and equipment expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the consolidated Statement of Cash Flows in the interim consolidated financial statements due to effect of accruals related to these expenditures and the inclusion of a capital lease.

Generation capital expenditures decreased by $10 million in the third quarter and decreased by $53 million year to date compared with the same periods in the prior year. The decrease is mainly due to lower spending on the Revelstoke Unit 5 Installation and the G.M. Shrum Transformers Replacement, as these projects were placed into service by the end of the third quarter of fiscal 2011, and also the Terzaghi Spillway Gate Reliability Upgrade. This is partially offset by increased spending on the Mica SF_6 GIS Replacement and the Fort Nelson Resource Smart Upgrade.

Transmission lines and substations capital expenditures increased by $29 million in the third quarter and increased by $54 million year to date compared with the same period in the prior year. This is mainly due to increased spending on the Saanich Peninsula Project and the Central Vancouver Island Project. The increase in the quarter is also due to higher expenditures on the Columbia Valley Transmission Project and the Northwest Transmission Line, and the year to date increase is also attributable to a right of way purchase.

General capital expenditures decreased by $23 million in the third quarter and decreased by $32 million year to date compared with the same period in the prior year, primarily due to lower expenditures on vehicle purchases, as many units were replaced in the second half of fiscal 2010, and lower expenditures related to the Port Mann Bridge highway relocation. The year to date decrease was also due to lower expenditures on the Home Purchase Offer Program (HPOP) in Tsawwassen, partially offset by construction commencing at Horne Payne, purchase of the Edmonds Annex Building and higher IT&T expenditures.

In accordance with Canadian GAAP, the costs of the energy purchase agreement (EPA) with Island Co-Generation (ICG) of $171 million are accounted for as a capital lease rather than a procurement of energy from an IPP in fiscal 2011.

RISK MANAGEMENT

BC Hydro faces risks to its business that could significantly impact its ability to achieve its short- and long-term financial, social and environmental goals. The goal of risk management is not to eliminate risks, but rather to mitigate them to levels which are commensurate with the potential benefits to be derived. Similarly, BC Hydro's risk management strategies aim to mitigate risks through a consistent risk management process that is applied to day-to-day business activities as well as to specific projects and initiatives. BC Hydro's Chief Risk Officer is responsible for facilitating this risk management process and promoting strong oversight of significant risks by the BC Hydro Risk Management Committee. BC Hydro's Board of Directors also plays a key role in the oversight of risk management, as the Board must understand the risks being taken by BC Hydro and ensure that processes are in place to appropriately manage the risks. BC Hydro's operations involve a broad spectrum of risks ranging from those commonly associated with any business to catastrophic societal loss risks that would have severe effects on entire regions.

The generation, transmission and distribution of electricity inherently results in certain safety risks to both BC Hydro workers and the public. To manage worker and public safety, BC Hydro relies on education and training, safe design, safety practice regulations and communication. BC Hydro also prepares emergency response plans to limit injury and loss to life and to restore electric service. The large dams represent a catastrophic loss risk (low probability but high consequence) in terms of life, safety, financial, environmental and reputation. This dam failure risk is managed through a comprehensive dam safety management system involving dam safety professionals and experts.

Significant risks to the reliability of BC Hydro's system include aging infrastructure and the impact of weather. Reliability risks could also result from either a lack of available generation supply or the associated transmission capacity to meet customer demand. BC Hydro manages these risks through long-term planning, asset maintenance and replacement programs, emergency response programs, a diverse supply of energy options, and through cooperative support arrangements with neighbouring utilities.

The system inflow energy for fiscal 2011 is expected to be 85 per cent of normal. With additional IPP energy expected in fiscal 2012, the system energy deficit is expected to be much smaller than in fiscal 2011. Lower market prices and reduced domestic load have partially mitigated the impact of below-normal system inflow on cost of energy. Several factors constrain BC Hydro's ability to use its stored system energy to meet load throughout the year. These factors include generating unit outages at major plants (forced outages and capital projects) as well as water management constraints which limit generation at the major plants during some periods. Even if the system had an annual energy surplus, some electricity purchases may still be required during constrained periods of the year (e.g. fall, winter, early spring), while electricity sales may be needed during other periods to minimize spill from system reservoirs. The value of these purchases and sales is subject to market price risk. Electricity demand is generally increasing as B.C.'s population increases; however this demand can be volatile, particularly from large industrial and commercial customers whose consumption is often driven by export markets and world commodity prices. BC Hydro's risk mitigation strategy is to achieve energy security, primarily from domestic sources and through energy conservation and efficiency. BC Hydro regularly models the projected supply-demand balance of the system over the short to medium term in an effort to meet demand in the most cost effective manner.

Legal and regulatory requirements for First Nation consultation, claims of historic grievances, land claims, and service reliability issues pose risks to BC Hydro. These risks are managed through a comprehensive aboriginal relations program. Building mutually-beneficial relationships with First Nations reduces financial, legal and operating risks.

In meeting its financial performance targets, BC Hydro faces many risks including uncertain economic conditions, variable costs and revenues as driven by energy costs, energy demand, interest and foreign exchange rates, pension obligations and energy trading. Of these, risks associated with energy costs – specifically water inflows and energy market prices – are the largest. Tariff rates are set based upon BC Hydro's cost forecast and allowed return on deemed equity. Many financial risks (differences between forecast and actual costs) associated with uncontrollable costs are mitigated through regulatory deferral accounts. Increasing costs due to aging infrastructure, the modernization and refurbishment of the electricity system, the need for new supply and the need to manage environmental impacts create challenges for BC Hydro in maintaining a cost advantage.

BC Hydro's energy trading subsidiary, Powerex, is exposed to the risk of variable market prices and counterparties who might not meet their obligations. Powerex manages these risks by operating through defined limits that are regularly reviewed by both the Powerex and BC Hydro Boards of Directors.

The economic contraction has continued to improve the labour supply of engineers and senior managers and has also improved BC Hydro's ability to attract and retain staff in a variety of roles. The economic downturn has also had the effect of delaying employee retirements; however this may result in a sudden surge of retirements in the future with shorter notice periods. Apprentice programs and contingent workers partially mitigate this risk. In addition, the return on pension fund assets and the market discount rate at year end can have a significant impact on the cost of providing employee future benefits.

Areas where BC Hydro is exposed to the risk of non-compliance with environmental regulations include the release of hazardous materials into the environment and endangerment of wildlife and their habitats. These risks are managed through a variety of site specific risk management strategies.

Other risks to BC Hydro have not changed materially from the Management Discussion and Analysis in the 2010 Annual Report.

FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in March 2010 forecasted a net income of $609 million for fiscal 2011. BC Hydro prepared an updated forecast in January 2011 which is incorporated into the March 2011 Service Plan that forecasts a net income of $571 million for fiscal 2011. The decrease in the forecast net income is due to the impact of the NSA on BC Hydro's Fiscal 2011 RRA.

BC Hydro's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, weather temperatures, interest rates and foreign exchange rates. The updated forecast for fiscal 2011 assumes lower than average water inflows (83 per cent of average), customer load of 50,623 GWh, average market electricity prices of US $32.35/MWh, short-term interest rates of 0.81 per cent and a U.S. dollar exchange rate of US $0.9683, an allowed return on equity of 14.37 per cent, and a rate increase of 6.11 per cent for fiscal 2011.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) DECEMBER 31, 2010

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)	*For the three months ended December 31*		*For the nine months ended December 31*	
		(Revised Note 1)		*(Revised Note 1)*
(in millions)	**2010**	2009	**2010**	2009
Revenues				
Domestic	**$ 936**	$ 884	**$ 2,488**	$ 2,358
Trade	**328**	633	**1,052**	2,122
	1,264	1,517	**3,540**	4,480
Expenses				
Operating Costs				
Cost of energy (Note 8)	**567**	904	**1,649**	2,728
Other operating expenses (Note 8)	**419**	372	**1,186**	1,065
	986	1,276	**2,835**	3,793
Finance Charges	**107**	128	**324**	385
	1,093	1,404	**3,159**	4,178
Net Income	**$ 171**	$ 113	**$ 381**	$ 302

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)	*For the three months ended December 31*		*For the nine months ended December 31*	
(in millions)	**2010**	2009	**2010**	2009
Net Income	**$ 171**	$ 113	**$ 381**	$ 302
Other Comprehensive Income (Loss) (Note 7)	**11**	7	**(2)**	84
Comprehensive Income	**$ 182**	$ 120	**$ 379**	$ 386

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(Unaudited)	*For the nine months ended December 31*	
(in millions)	**2010**	2009
Retained Earnings, Beginning of Period	**$ 2,621**	$ 2,221
Net Income	**381**	302
Accrued Payment to the Province	**(216)**	(123)
Retained Earnings, End of Period	**$ 2,786**	$ 2,400

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEET

(Unaudited) (in millions)	As at December 31 2010	(Revised Note 1) As at March 31 2010
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 17**	$ 9
Accounts receivable and accrued revenue	**612**	650
Inventories (Note 2)	**158**	118
Prepaid expenses	**90**	131
Current portion of derivative financial instrument assets	**223**	434
	1,100	1,342
Other Assets		
Property, plant and equipment	**14,784**	13,822
Intangible assets	**324**	282
Regulatory assets (Note 4)	**2,470**	2,157
Sinking funds	**98**	96
Employee future benefits	**304**	313
Derivative financial instrument assets	**104**	86
	18,084	16,756
	$ 19,184	$ 18,098
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 1,108**	$ 1,101
Current portion of long-term debt	**2,358**	2,074
Current portion of derivative financial instrument liabilities	**179**	393
	3,645	3,568
Other Liabilities		
Long-term debt	**9,347**	8,727
Regulatory liabilities (Note 4)	**324**	444
Deferred contributions	**1,108**	1,079
Derivative financial instrument liabilities, long-term	**263**	224
Other long-term liabilities	**1,600**	1,382
	12,642	11,856
Shareholder's Equity		
Contributed surplus (Note 10)	**60**	-
Retained earnings	**2,786**	2,621
Accumulated other comprehensive income (Note 7)	**51**	53
	2,897	2,674
	$ 19,184	$ 18,098

Commitments and Contingencies (Note 9)

See accompanying notes to the interim consolidated financial statements.

Approved on behalf of the Board:

Dan Doyle
Chairman

Tracey L. McVicar
Chair, Audit and Risk Management Committee

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)	*For the three months ended December 31*		*For the nine months ended December 31*	
(in millions)	**2010**	2009	**2010**	2009
Operating Activities				
Net income	**$ 171**	$ 113	**$ 381**	$ 302
Regulatory account transfers	**(120)**	(85)	**(423)**	(368)
Adjustments for non-cash items:				
Amortization of regulatory accounts (Note 4)	**24**	17	**18**	50
Amortization expense and depreciation	**121**	106	**354**	315
Foreign exchange translation (gains) losses	**(5)**	(3)	**(3)**	(29)
Unrealized loss (gains) on mark-to-market	**54**	29	**(11)**	21
Employee benefit plan expenses	**12**	11	**36**	33
Other items	**17**	17	**26**	6
	274	205	**378**	330
Changes in non-cash working capital:				
Accounts receivable and accrued revenue	**(196)**	(159)	**57**	53
Accounts payable and accrued liabilities	**(10)**	(77)	**(117)**	(377)
Prepaid expenses	**100**	137	**47**	99
Inventories	**4**	20	**(40)**	(13)
	(102)	(79)	**(53)**	(238)
Cash provided by operating activities	**172**	126	**325**	92
Investing Activities				
Property, plant and equipment and intangible asset expenditures	**(383)**	(370)	**(1,168)**	(1,139)
Deferred contributions	**13**	23	**50**	56
Other items	**(1)**	(6)	**(3)**	(15)
Cash used in investing activities	**(371)**	(353)	**(1,121)**	(1,098)
Financing Activities				
Long-term debt				
Issued	**-**	823	**593**	1,613
Retired	**-**	(200)	**(150)**	(632)
Revolving borrowings, included in long-term debt	**197**	(342)	**408**	(103)
Payment to the Province	**-**	-	**(47)**	-
Other items	**-**	(29)	**-**	(23)
Cash provided by financing activities	**197**	252	**804**	855
Increase (decrease) in cash and cash equivalents	**(2)**	25	**8**	(151)
Cash and cash equivalents, beginning of period	**19**	14	**9**	190
Cash and cash equivalents, end of period	**$ 17**	$ 39	**$ 17**	$ 39
Supplemental Disclosure of Cash Flow Information				
Interest paid	**$ 171**	$ 144	**$ 449**	$ 399
Non-cash transaction:				
Capital lease obligation included in other liabilities	**$ -**	$ -	**$ 171**	$ -

See accompanying notes to the interim consolidated financial statements.

NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) DECEMBER 31, 2010

DESCRIPTION

British Columbia Hydro and Power Authority (BC Hydro or the Company) was established in 1962 as a Crown Corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, distribute and supply power. BC Hydro's corporate purpose is to provide "Reliable power, at low cost, for generations." BC Hydro is subject to regulation (Note 4) by the British Columbia Utilities Commission (BCUC) which, among other things, approves the rates BC Hydro charges for its services.

BC Hydro owns and operates electric generation and distribution facilities in the Province. BC Hydro also owns transmission facilities in the Province that were operated by British Columbia Transmission Corporation (BCTC), an independent Crown Corporation of the Province up to July 5, 2010. As of July 5, 2010, BCTC and BC Hydro were integrated as a single organization as a result of the *Clean Energy Act* (Note 10).

NOTE 1: ACCOUNTING POLICIES

Basis of Presentation

The interim consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) for preparation of interim financial statements and do not conform in all respects to the disclosure requirements for annual financial statements. BC Hydro follows certain accounting practices that reflect the effects of regulation, and differ from the accounting practices for enterprises that do not operate in a rate-regulated environment. These interim consolidated financial statements and the notes should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2010 Annual Report.

These interim consolidated financial statements follow the same accounting policies as those described in BC Hydro's 2010 Annual Report.

Certain amounts in the prior year's statements related to inventories, prepaid expenses, trade revenue and expense, and regulatory assets and regulatory liabilities have been reclassified to conform to the current year's presentation. Certain amounts in the prior year's statement of operations have been reclassified to conform to a change in the current year's classification of operating expenses to a presentation of costs based on the nature of the expenditures. Amounts previously presented as operations, maintenance and administration costs are now classified by the nature of the expense as outlined in Note 8.

In addition, the Company has changed its presentation of the impact of regulation on its statement of operations. In prior periods the impact of regulatory accounting was shown as a single line item whereas in the current period the impact of regulation is netted against the corresponding expense or revenue line item in the statement of operations. This change results in the Company's presentation being more consistent with other regulated utilities in Canada. Comparative balances have been reclassified to conform with the current period's presentation. Detail on regulatory account transfers can be found in Note 4.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets, liabilities and commitments at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Significant items subject to management estimates and assumptions include the determination of the allowance for doubtful accounts, the fair value of sinking funds and derivative financial instruments, the actuarial assumptions used to value the employee future benefit plans, the useful lives of property, plant and equipment and intangible assets, amounts for accrued liabilities and contingencies, and the accrual for unbilled revenue at period end. Actual results could differ from these estimates.

NOTE 2: INVENTORIES

(in millions)	***As at December 31 2010***	*As at March 31 2010*
Materials and supplies	**$ 80**	$ 77
Natural gas trading inventories	**78**	41
	$ 158	$ 118

NOTE 3: SEASONALITY OF OPERATING RESULTS

Due to the seasonal nature of BC Hydro's operations, the interim consolidated statement of operations is not indicative of operations on an annual basis. Seasonal impacts of weather, including its impact on water inflows, energy consumption within the region and market prices of energy, can have a significant impact on BC Hydro's operating results.

NOTE 4: REGULATION

BC Hydro is regulated by the BCUC, and both entities are subject to general or special directives and directions issued by the Province. BC Hydro operates primarily under a cost of service regulation as prescribed by the BCUC. Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province. Calculation of its revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

BC Hydro applies various accounting policies that differ from GAAP for enterprises that do not operate in a rate-regulated environment. Generally, these policies result in deferral and amortization of costs and recoveries to allow for adjustment of future rates. In the absence of rate-regulation, these amounts would otherwise be included in the determination of net income in the period the amounts are incurred. These accounting policies support BC Hydro's regulation and have been established through ongoing application to and approval by the BCUC. To the extent that a regulatory account has been, or will be applied for, and in management's estimate, acceptance of deferral treatment by the BCUC is considered probable, the Company will defer such costs in advance of a final decision of the BCUC. Should the BCUC deny the application for deferral, the amount deferred would be recorded in net income at such time.

BC Hydro's fiscal 2011 Revenue Requirement Application (RRA) was filed with the BCUC on March 3, 2010 requesting a 6.11 per cent rate increase. BC Hydro also requested that the Deferral Account Rate Rider (DARR) increase by 3 per cent to 4.0 per cent in order to partially recover the net balances of the Heritage Deferral Account, Non-Heritage Deferral Account, Trade Income Deferral Account and BCTC Deferral Account ("energy deferral accounts"). The rate increases were approved by the BCUC on an interim basis effective April 1, 2010. An Evidentiary Update was filed with the BCUC on July 9, 2010 proposing to defer recovery in fiscal 2011 of higher than previously forecast energy costs. A Negotiated Settlement Process (NSP) started in September 2010, and reached an agreement in November 2010.

On December 2, 2010, the BCUC approved the Negotiated Settlement Agreement (NSA) for BC Hydro's fiscal 2011 RRA. The final approved rate increase is 6.11 per cent with a 4.71 per cent credit applied for the period January 1 to March 31, 2011 to reflect the NSA adjustments. The NSA also confirmed the DARR of 4.0 per cent for the period from April 1, 2010 to December 31, 2010, inclusive, and 2.5 per cent thereafter.

Additional provisions in the NSA which impacted third quarter of fiscal 2011 results included a $5.5 million write-down of the Procurement Enhancement Initiative (PEI) Regulatory Account balance and $10.3 million of the Demand Side Management (DSM) Regulatory Account balance.

Results for the nine month period ended December 31, 2010 reflect the final rate increase for fiscal 2011 and provisions in the BCUC approved NSA which affect year to December 31, 2010 fiscal 2011 results.

Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. For the three and nine months ended December 31, 2010, the impact of regulatory accounting has resulted in an increase to net income of $92 million and $408 million, respectively (three and nine months ended December 31, 2009 – $69 million and $301 million increase, respectively).

(in millions)	*(Revised) April 1 2010*	*(Note 10) BCTC Transfers*	*Addition (Reduction)*	*Amortization*	*Net change*[1]	*December 31 2010*
Regulatory Assets						
Heritage Deferral Account	$ 325	$ -	$ 13	$ (50)	$ (37)	$ 288
Non-Heritage Deferral Account	119	-	174	(19)	155	274
BCTC Deferral Account	18	-	2	(3)	(1)	17
Trade Income Deferral Account	122	-	108	(19)	89	211
Demand-Side Management Programs	442	-	73	(48)	25	467
First Nation Negotiations, Litigation and Settlement Costs	399	-	1	(1)	-	399
Non-Current Pension Cost	86	-	1	(13)	(12)	74
Site C	60	-	31	-	31	91
Environmental Compliance	321	-	9	(4)	5	326
Other Regulatory Accounts	265	27	36	(5)	31	323
Total Regulatory Assets	2,157	27	448	(162)	286	2,470
Regulatory Liabilities						
Future Removal and Site Restoration Costs	159	-	-	(14)	(14)	145
Foreign Exchange Gains and Losses	101	-	3	-	3	104
Finance Charges	104	-	11	(78)	(67)	37
Other Regulatory Accounts	80	2	8	(52)	(44)	38
Total Regulatory Liabilities	444	2	22	(144)	(122)	324
Net Regulatory Asset	$ 1,713	$ 25	$ 426	$ (18)	$ 408	$ 2,146

[1] Net change excludes BCTC transfers

Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province.

On May 28, 2010, the BCUC approved BC Hydro's application to establish the Environmental Compliance regulatory account pertaining to compliance with Federal Polychlorinated Biphenyl (PCB) Regulations and the remediation of environmental contamination at one of the Company's properties.

Other regulatory asset accounts with individual balances less than $65 million include the following: Depreciation Study Adjustments, Contributions in Aid of Construction Amortization Variance, Capital Project Investigation Costs, Procurement Enhancement Initiative Costs, Smart Metering and Infrastructure Project Costs (SMI), GM Shrum Unit 3 Outage, Home Purchase Option Program, Return on Equity (ROE) Adjustment and Waneta Rate Smoothing.

BC Hydro will be applying for approval to defer fiscal 2011 costs related to SMI, which are $5 million (asset) as at December 31, 2010, prior to the end of the fiscal year.

Other regulatory liability accounts with individual balances less than $65 million include the following: Net Employment Costs, Amortization of Capital Additions, Taxes, and Storm Damage.

NOTE 5: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province. Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province and the imposed requirement to maintain a debt to equity ratio not exceeding 80:20.

BC Hydro monitors its capital structure on the basis of its debt to equity ratio. For this purpose, BC Hydro defines debt as long-term debt less investments held in sinking funds, temporary investments and cash and cash equivalents. Equity as defined for regulatory purposes comprises retained earnings, contributed surplus and accumulated other comprehensive income.

BC Hydro manages its capital so as not to exceed the 80:20 debt to equity ratio as required by the Province. During the period, there were no changes in this approach to capital management.

The debt to equity ratio at December 31, 2010 and March 31, 2010 was as follows:

(in millions)	***As at December 31 2010***	*As at March 31 2010*
Total long-term debt, net of sinking funds	**$ 11,607**	$ 10,705
Less: cash and cash equivalents	**(17)**	(9)
Net Debt	**$ 11,590**	$ 10,696
Retained earnings	**$ 2,786**	$ 2,621
Contributed surplus (Note 10)	**60**	-
Accumulated other comprehensive income	**51**	53
Total Equity	**$ 2,897**	$ 2,674
Net Debt to Equity Ratio	**80 : 20**	80 : 20

Under a Special Directive from the Province, BC Hydro is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of BC Hydro's distributable surplus for the most recently completed fiscal year assuming that the debt to equity ratio, as defined by the Province, after deducting the Payment, is not greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment will be based on the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. The dividend accrued year to date at December 31, 2010 is $216 million which is below 85 per cent of the distributable surplus due to the 80:20 cap.

In November 2010, Treasury Board approved a change in how the allowed return on equity (ROE) is calculated. Allowed ROE will now be based on an assets-in-service rate base instead of debt and equity. This change will take effect April 1, 2011 subject to final approval by the Province which is expected in the fourth quarter of fiscal 2011.

NOTE 6: EMPLOYEE FUTURE BENEFITS

BC Hydro's cost for employee future benefits for the three and nine months ended December 31, 2010 was $28 million and $82 million, respectively (fiscal 2010 – $24 million and $72 million, respectively).

NOTE 7: OTHER COMPREHENSIVE INCOME (LOSS) & ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Other Comprehensive Income (Loss)

(in millions)	*For the three months ended December 31* **2010**	2009	*For the nine months ended December 31* **2010**	2009
Other Comprehensive Income				
Unrealized loss on derivatives designated as cash flow hedges	**$ (23)**	$ (17)	**$ (23)**	$ (129)
Reclassification to income of loss on derivatives designated as cash flow hedges	**34**	24	**21**	213
Other Comprehensive Income (Loss)	**$ 11**	$ 7	**$ (2)**	$ 84

Accumulated Other Comprehensive Income (Loss)

(in millions)	*For the nine months ended December 31* **2010**	2009
Accumulated other comprehensive income (loss), beginning of period	**$ 53**	$ (42)
Other comprehensive (loss) income for the period	**(2)**	84
Accumulated Other Comprehensive Income, End of Period	**$ 51**	$ 42

NOTE 8: OPERATING COSTS

Cost of Energy

(in millions)	*For the three months ended December 31* **2010**	2009	*For the nine months ended December 31* **2010**	2009
Electricity and gas purchases	**$ 467**	$ 765	**$ 1,274**	$ 2,305
Water rentals	**65**	86	**218**	229
Transmission charges	**35**	53	**157**	194
Cost of Energy	**$ 567**	$ 904	**$ 1,649**	$ 2,728

Other Operating Expenses

(in millions)	*For the three months ended December 31* **2010**	2009	*For the nine months ended December 31* **2010**	2009
Personnel expenses	**$ 131**	$ 114	**$ 402**	$ 350
Materials and external services	**144**	162	**430**	440
Amortization and depreciation	**145**	121	**396**	361
Grants and taxes	**46**	43	**136**	129
Other costs	**20**	(3)	**14**	(8)
Capitalized costs	**(67)**	(65)	**(192)**	(207)
Other Operating Expenses	**$ 419**	$ 372	**$ 1,186**	$ 1,065

For the three and nine months ended December 31, 2010, amortization and depreciation is shown net of amortization of regulatory accounts of $23 million and $41 million, respectively (three and nine months ended December 31, 2009 — $15 million and $46 million, respectively).

NOTE 9: COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek refunds, damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At December 31, 2010, Powerex was owed US $265 million (CDN $264 million) by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

Due to the ongoing nature of the regulatory and legal proceedings against Powerex, management cannot predict the outcomes of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the California energy crisis. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that are ultimately collected or paid may differ from management's current estimates. Management has not disclosed the provision amounts or ranges of expected outcomes due to the potentially adverse effect on the process.

NOTE 10: INTEGRATION OF BCTC

On June 3, 2010, the Province enacted the *Clean Energy Act* (the Act) in the B.C. Legislature. The Act sets the foundation for a new future of electricity self-sufficiency powered by investments in clean, renewable energy across the province. The Act requires the integration of BC Hydro and BCTC into a single organization with one board of directors and executive, and the transfer of all BCTC assets, liabilities and employees to BC Hydro, effective July 5, 2010.

BC Hydro has accounted for the merger of BCTC on a continuity-of-interests basis as there is no substantive change in the ownership of BCTC arising from the transaction. The following assets and liabilities of BCTC were transferred to BC Hydro at their net book values on July 5, 2010:

(in millions)	
Assets	
Current assets	**$ 13**
Property, plant and equipment	**107**
Intangible assets	**28**
Regulatory assets	**25**
Other assets	**2**
Total Assets	**$ 175**
Liabilities	
Current liabilities	**$ 25**
Long-term debt	**70**
Other non-current liabilities	**20**
Contributed surplus	**60**
Total Liabilities & Equity	**$ 175**

In transferring its ownership interest in BCTC to BC Hydro, the Province's contribution has been included in contributed surplus.

The operating results of BCTC have been included in BC Hydro's consolidated statement of operations and comprehensive income from July 5, 2010. The operating results of BCTC for the period from April 1, 2010 to July 4, 2010 were not included in BC Hydro's consolidated statement of operations and comprehensive income, as management believes that it does not have a material impact on the consolidated financial statements. Comparative amounts presented in these consolidated financial statements have not been restated to reflect the financial position and results of operations as if the companies have been combined since their inception on the basis that the impact is not significant.

NOTE 11 SUBSEQUENT EVENTS

On January 4, 2011, BC Hydro transferred the ownership and operation of four domestic water systems referred to collectively as the Arrow Water Systems (AWS): Burton Water Corporation, Edgewood Water Corporation, Fauquier Water and Sewerage Corporation, and West Robson Water Corporation to the Regional District of Central Kootenay. BC Hydro will apply to the BCUC for a regulatory account to defer divestiture costs relating to the transfer in order to recover them through rates in future years.